SPACE HEATING AT THE NAVAL AIR STATION, FALLON, NEVADA--AN ECONOMIC ANALYSIS OF A GEOTHERMAL ALTERNATIVE

Richard Gaze Kovach
and
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Monterey, California

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by

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application at NAS Fallon, are synopsized. Using the benefit/cost results of these studies, a more detailed economic evaluation is then made of the proposed alternatives. Results of these economic extensions indicate that a geothermal heating system at NAS Fallon is a basically sound investment, given the correctness of assumptions made in each study. Several conclusions and recommendations are presented based on the study results.

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I. INTRODUCTION

In the past three decades, petroleum has been a major energy source for most of the industrialized nations. In the late 1940's, several preeminent scientists predicted that the oil wells of the world would never run dry, in fact, the earth was "manufacturing oil faster than we can consume it" [1]. At present, petroleum constitutes about 45% of the world's primary energy consumption; coal represents 30%; natural gas 18%; with nuclear energy and hydroelectric sources making up the remaining 7%. The breakdown of energy consumption by countries is as follows;

USA	28%
USSR	17%
Eastern Europe	7%
China	6%
Japan	6%
West Germany	4%
Canada	3%
United Kingdom	3%
Other nations	26%

In 1975, the U.S. Geological Survey estimated that,based on projected production estimates, the current domestic reserves of petroleum in the United States will be exhausted between 1993 and 2000. (New discoveries could delay exhaustion by 5 to 10 years).

On the world scene, U.S. Navy estimates show that by 1985 world petroleum demand will exceed supply. At the 1966-1975 average demand growth rate of 5.7% per year, world petroleum resources that can be economically recovered will be exhausted between the years 2006 and 2010. The use of alternative energy sources and conservation to keep current demand levels constant would delay petroleum exhaustion until between 2050 and 2070.

In FY 1977, the U.S. Navy consumed energy equivalent to 81 million barrels of oil, with approximately 38% (or 31 million barrels) being accounted for by shore installations.

The spiraling cost of petroleum products has made conservation and the use of alternative energy sources attractive, if not vital, with respect to budget restraints. One potential energy resource is the use of heat from the earth to heat buildings (space heating), thereby saving petroleum. This heat from the earth is referred to as geothermal energy.

Geothermal energy is one of the largest and least used energy resources available to man [2]. For example, the total volume of the earth is about 260 cubic miles, and, except for the extreme outer surface, it is hot. The exact temperature is not known, but an example of its potential is illustrated as follows: a 40 cubic mile "chunk" of rock at a temperature of 360^{o}F when cooled 160^{o}F to 200^{o}F would have provided all the energy requirements of the United States during the calendar year 1970 [3].

Using the heat from the earth is not a new idea. It started in 1913 in Italy where geothermal energy was used to generate electricity. The Lardello Field now produces over 365 million watts of electricity annually. Presently, Iceland, Japan, The U.S.S.R., Mexico, and The United States are producing electricity from geothermal steam produced from deep inside the earth. Iceland, Hungary, New Zealand, and the United States have also utilized geothermal heat for the heating of buildings (space heating).

In geothermally active areas, the use of this resource for energy generation has been proven economically sound. Geothermal energy generation represents a low cost and reliable (long-lived) resource which poses only moderate (and in most cases manageable) environmental problems. The development of this resource, however, generally does present some problems. First is the availability of the geothermal source. For most of the world, the earth's crust is approximately 20 miles (30 kilometers) thick, much too deep for today's drilling technology. Therefore, one must look to areas where the crust of the earth is thinner (no more than one or two miles, or about 1000 to 3000 meters). These areas occur where the mobile crustal plates of the earth collide producing such phenomena as volcanoes, crusts of rifting, and recent mountain building. These rifts allow for the (1) intrusion of molten rock to high levels in the crust; (2) deep circulation of groundwater; or (3) the heating of the shallow rock body, producing such geothermal features as geysers, fumaroles, and hot springs. Figure 1 indicates the regions where geothermal

activity is significant enough to make it an economically attractive venture. The second problem associated with the use of geothermal energy is that finding it is similar to searching for oil; one doesn't know the results until the well is drilled. Just as an oil well will produce various grades of oil, so the geothermal well produces "classes" of geothermal energy. For example, current classifications are as follows[4]:

1) HOT WATER - this field will contain a water reservoir at temperatures ranging from 140° F to 212°F (60°C to 100°C). Such fields are useful in space heating and various industrial purposes.

2) WET STEAM FIELDS - contain pressurized water reservoirs at temperatures exceeding 212°F (100°C). When the hot water is brought to the surface, and the pressure is sufficiently reduced, some of the water will be flashed into steam, so that the resulting fluid is a mixture of water and steam under saturated conditions. Water usually predominates, but this type of field is useful for generation of electrical power and for other purposes.

3) DRY STEAM FIELDS - yielding dry superheated steam at the wellhead, at pressures above atmospheric. The degree of superheat may vary from 0°F to 120°F (-17°C to 50°C).

Geologically, wet steam and dry steam fields are similar, as emphasized by the fact that in some cases wells have alternately produced wet steam and dry steam [5].

The nomenclature used in identifying geothermal wells is far from being standardized throughout the industry.

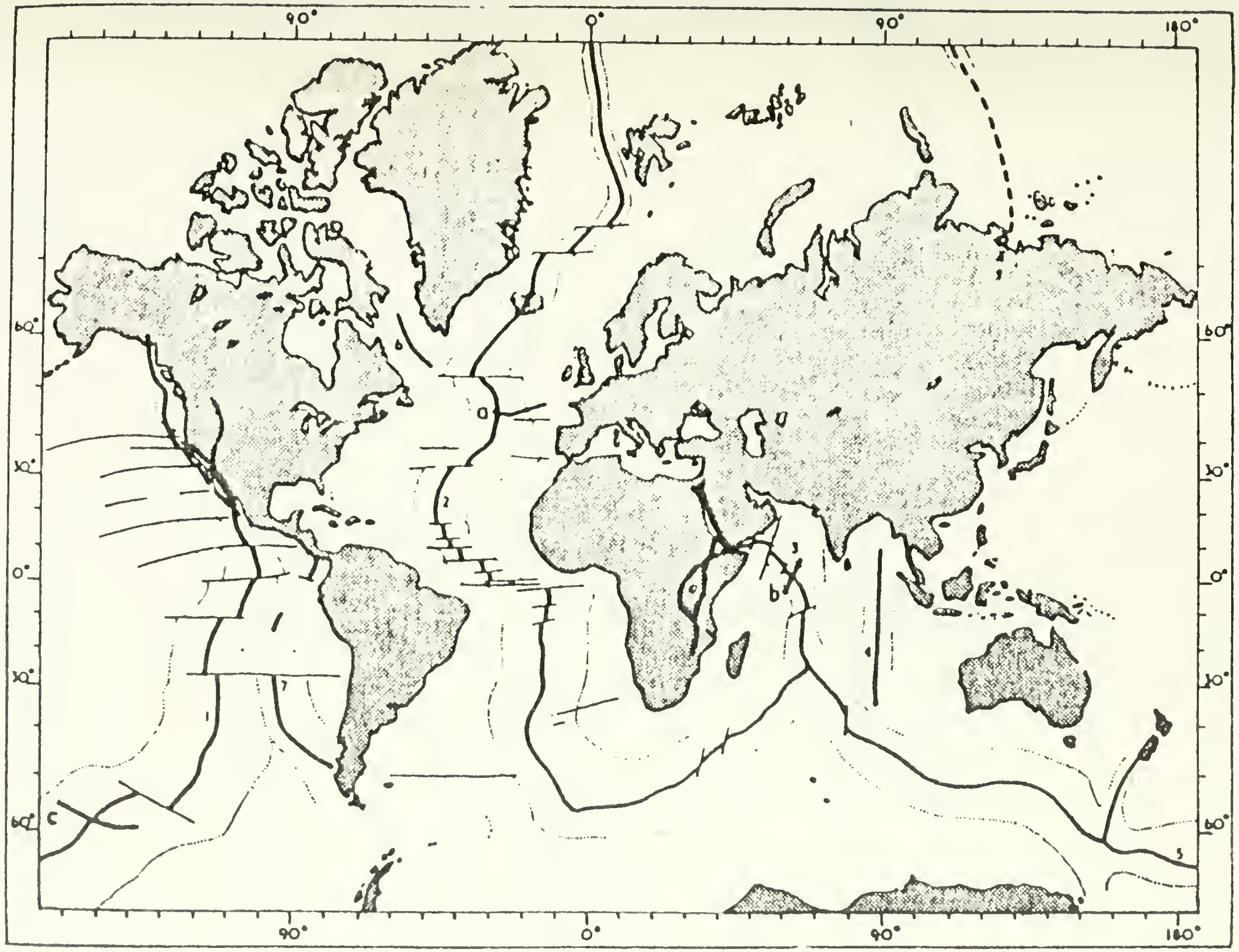
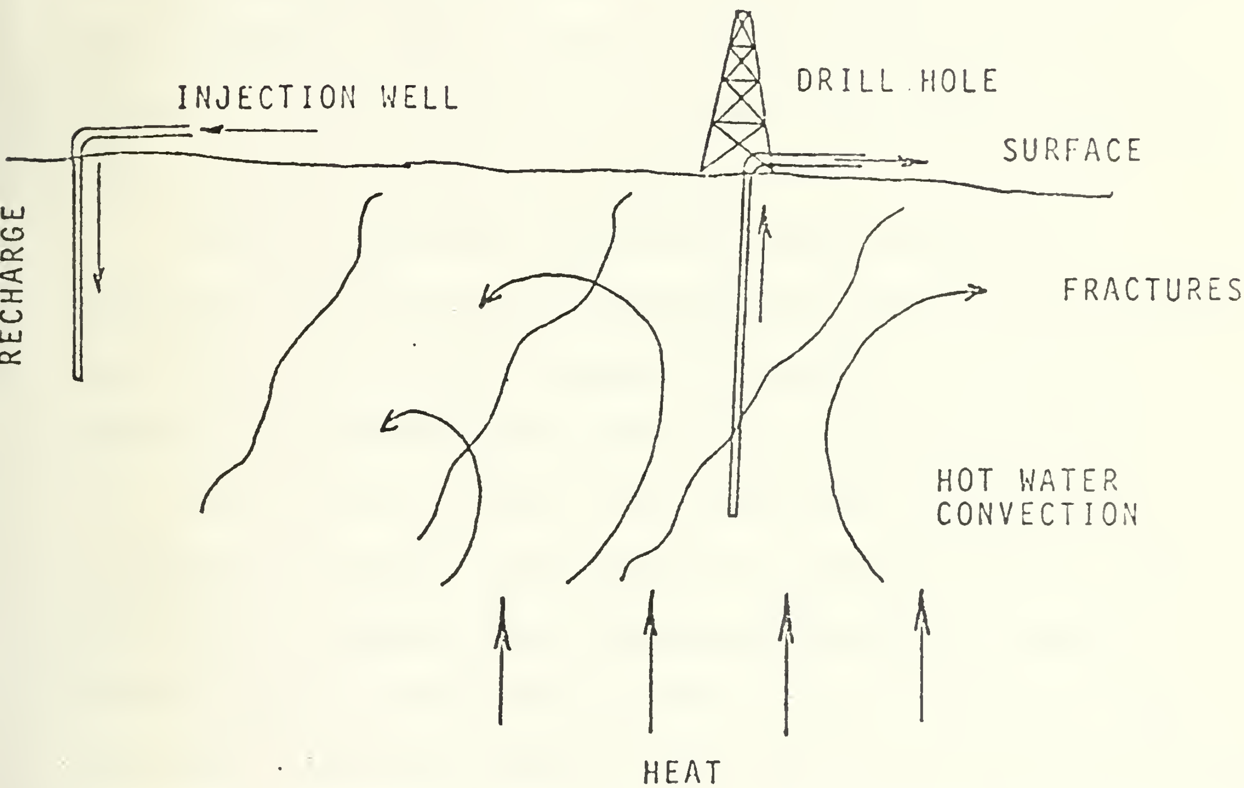


Fig. 1. The Mid-Ocean ridges. The heavy line represents the crest of the ridge and the central valley: the thin lines across the ridge are transverse faults. (From D.H. Matthew, International Dictionary of Geophysics, p.981.

Many scholars will refer to a vapor dominated system or a hot water dominated system, but where one is dominated by steam or hot water, at elevated pressures it is difficult to identify.

The "production" of the hot water is accomplished by the circulation of ground water as indicated by figure 2 [4]



. 2. High Temperature Geothermal System Flow Controlled by Fractures.

The source of heat is probably molten rock or rock which has been solidified in the past few tens of thousands of year, lying at a depth of perhaps 3 to 6 miles (5000 to 10,000 meters). Normal groundwater circulates in open fractures, and removes heat from these deep hot rocks by

convection. Temperatures are uniform over large volumes of the reservoir. Recharge of cooler groundwater takes place at the margin of the system through circulation down fractures. The water from this type of formation, which is located at relatively shallow depths (3000 feet or approximately 1000 meters), will normally be at a temperature below the boiling point. With today's technology, the low temperature hot water field can only be utilized for space heating. This is due to the relatively low energy potential contained in the hot water vice that is contained in saturated or superheated steam wells.

Current technology restricts the generation of geothermal electricity to steam bearing wells. Space heating, requiring a much smaller energy potential, can be most economically accomplished using a hot water source [6].

Returning to figure 1 and examining the operation of geothermal wells, the technique is rather basic. The hot water is removed from the ground and may be piped directly to the unit being heated, or put through a heat exchanger, heating a second liquid that will circulate through the enclosed system.

In Iceland where the chemical impurities in the geothermal water is rather low, the hot water is piped directly to the individual units to be heated. However, in most other areas, the geothermal water is more often heavily contaminated with dissolved solids such as sodium chloride, calcium chloride, potassium chloride, boron, arsenic, and other chemicals in a wide range of combinations and concentrations, the liquid is usually impractical for direct use in a

system, because of its corrosive qualities. Once the heat has been extracted from the water the same chemicals preclude the direct disposal into natural water bodies. The most acceptable and commonly used method of disposal is to reinject the liquid back into the formation, at a precise location and depth so as not to contaminate surface or groundwater. The reinjection also helps to maintain the balance of the water system.

The geothermal system is rather simple. It requires that a shallow well be sunk, the hot water pumped through a heat exchanger, then returned to the ground. The area utilizing the space heating must be near the geothermal heat source, which greatly reduces the usefulness of such a system. The problems associated with high temperature deep well geothermal drilling and utilization is vastly more complex, and will not be discussed in this thesis.

With this basic explanation of geothermal energy, the next section will explore the costs associated with utilizing geothermal energy for space heating.

II. GEOTHERMAL COST FACTORS

In selecting a region for potential geothermal energy, the most obvious situation would be the presence of some type of thermal activity. Careful study of the fault zones, volcanic centers and hot springs is required before selecting a site for further prospecting. Once the area has been selected, the best location for exploratory drilling will be based on surface activity, geology, hydrogeology, geochemistry, detection of anomalies in the Earth's magnetic and gravity fields and electric resistivity of the Earth's strata [7]. The final event will be the drilling of a test well to depths of 3000-8000 ft. (approximately 900-2500 meters).

Drilling for geothermal energy employs the same basic techniques used by the Petroleum Industry. In its most simplistic form, the procedure involves a drill bit that is rotated on the end of drill piping (called a drill string). As the drill rotates it has "teeth" that grind rock. The rock, now in a pulverized state, must be removed by forcing a slurry of water and other chemicals (forming a solution called Mud) down the center of the drill string, over the drill bit, picking up the rock chips, and up the outside of the drill string to the surface. Figure 3 diagrams the drill string. In addition to removing the cuttings the

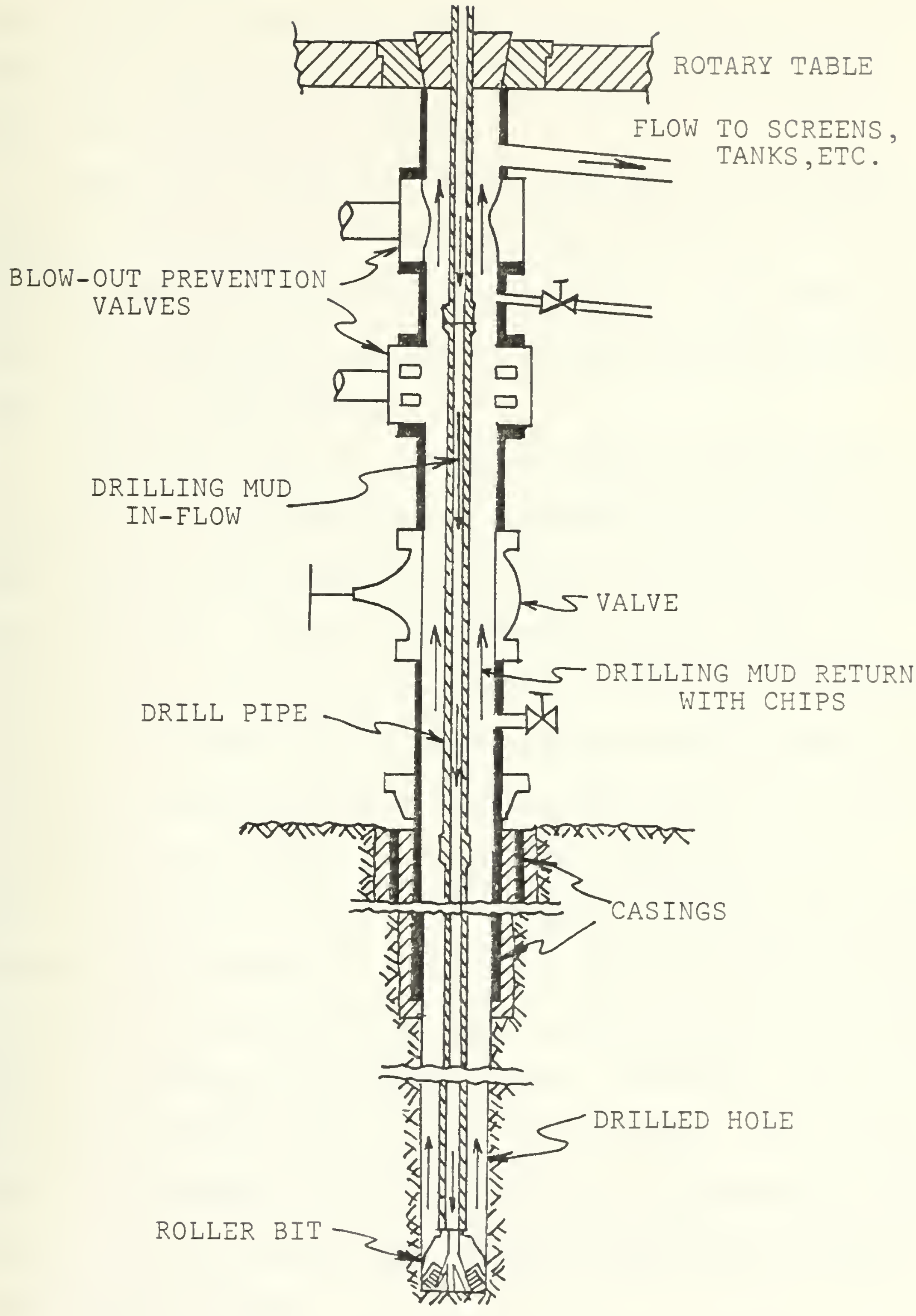


Fig. 3. Drilling String and Blowout Preventer Equipment. Source: Proceedings of the United Nations Conference on New Sources of Energy, Rome, 21-31 Aug. 1961, Vol. 3 Geothermal Energy:II, Page 125.

circulating fluid (mud) cools the drill bit, and keeps a positive head pressure on the well to prevent an eruption or "Blow Out" that could destroy the drill hole and drill rig, and could be costly to secure.

While the Petroleum Industry has drilled to depths in excess of 25,000 feet (7,600 meters) geothermal wells have not exceeded 10,000 feet (3,000 meters). Most production wells for geothermal energy are between 1,600 and 6,500 feet (500 - 2,000 meters).

Rock formations in geothermal areas consist mostly of volcanic or high density rock characterized by a high hardness index, high temperature gradient and extensive faulting and fissuring. Losses of circulating fluid (mud) is frequent and progress is often much slower than when drilling for oil or natural gas. Other necessary procedures that are time consuming require that special concrete collars be constructed around the well hole; these can be as deep as 10 feet (3 meters) and require grouting the surrounding ground. The purpose of the collar is to stop the migration of steam or hot water from around the outside of the drill hole and forming an erupting crater. Secondly, the collar provides a strong base to anchor the piping. The piping must be anchored in such a manner to allow expansion and contraction as the result of severe temperature changes down the well hole.

The high temperatures also require modification of materials for the drill hole piping. Generally, aluminum, bronze, and cast iron are unsuitable due to the tempering

effect caused by the elevated temperatures. The presence of hydrogen sulfide forming sulfuric acid has a severe corrosion and oxidation effect [8]. The high temperatures at lower depths also affects the drilling mud used, causing it to break down; likewise, the concrete used to line the well has a much lower strength due to the temperature effect. The result is a much higher cost per foot for drilling a geothermal well than either a gas or petroleum well.

There has been no standard costs developed for drilling geothermal wells, however, principle expense items are found in areas such as:

Surveys: topographical, and setting-out work
Main access roads
Secondary access roads
Excavation and filling
Site preparation
Consolidation grouting around wellhead
Drilling
Water supply
Drainage
Building Construction
Operation of central mud batching plant
Testing and observations during drilling

All of the above have a direct impact on the cost of developing the resource. The range of drilling costs varies from a low of about $30 per foot in Iceland to a

high of $135 per foot at the Geysers, north of San Francisco, California. (All amounts are in 1979 dollars).

The increased price of petroleum products has enhanced the attractiveness of alternative energy sources. Geothermal energy is in a position of major potential growth, yet it still must compete with the petroleum and natural gas industry for the same drilling and financial resources. Items such as drilling rigs, drill steel, and capital investment are difficult to obtain without government intervention/regulation [10].

The costs addressed thus far are only to obtain a production well. Once that is completed additional costs are involved.

The most capital intensive operation is the generation of electrical energy. This is economically feasible with today's technology only by using steam to drive a small (approximately 10 to 50 megawatts) turbine. By drilling several wells and using a number of small turbines the total field production can be raised in excess of 300 megawatts. Few areas in the world have the vapor dominated systems capable of generating electrical power.

One emerging alternative for geothermal energy is the utilization of hot water for space heating. That is, the heating of homes or small businesses utilizing heat in drying, greenhouse farming or manufacturing processes.

Drilling costs for low temperature space heating geothermal wells are the same as for those already discussed.The lower temperature water however, is usually found at shallower depths,less the 2000 feet (600 meters). To remove the geothermal heat the well fluid must be piped to the industry or community. Due to the heat loss in piping, transportation of more than 10 miles (16 kilometers) is considered excessive, although piping of hot water to distances of 30 miles (48 kilometers) is considered feasible with extremely high temperature water (300°F or 150°C) and a large concentration of the market. The longer distances, with inherent heat loss, plus the additional expense in piping systems and insulation, has the possibility of making the venture financially unattractive.

The primary concern in delivering the hot water is economy; several factors add to the costs already identified in drilling the production well. These factors include the heat load or demand on the system and the temperature of the water from the well. Both varaibles will determine how much water must be provided in gallons per minute (GPM) which in turn will dictate the size of piping and insulation required.

Normally, space heating installations are not engineered to provide 100 per cent of the load during the coldest day but rather something less, with small booster boilers providing the additional heating when needed. It is most economical to allow the geothermal system to operate 100 per cent capacity, utilizing the

auxillary boilers when required. By operating the system at 100 per cent, the maximum heat transfer is accomplished, returning the lowest cost per BTU utilized. Attempting to design for maximum heating would normally require larger piping (for increased water flow), larger pumps and conceivably more production wells, the result would be that 95 per cent of the time the system would have unused capacity and therefore, it would operate inefficiently.

The geothermal water is usually high in concentrations of various sustances already listed in the introduction: which prevents its direct use in space heating systems due to potential corrosion. The predominant method of extracting the heat without the dissolved impurities is the use of a heat exchanger. The heat exchanger is a large container with tubes. The geothermal hot water enters one end of the container, flows through the tubes and exits the other end. From an orifice on the bottom of the heat exchanger, but separated from the contaminated geothermal hot water, fresh water is introduced around the tubes that carry the hot geothermal water. The heat is transferred or "exchanged" to the fresh water to be pumped to the units requiring the heat. By this method, the heat is transferred to fresh water without contamination. After passing through a radiator of some type and giving up its heat, the water is returned to the heat exchanger to repeat the cycle.

It must be recognized that a distribution system must be provided from the heat exchanger to the units served. In a residential setting where units were previously heated by individual central units, the cost of piping to each residential unit, then a return line to the heat exchanger, could be extremely expensive. Certainly, new housing units would have a much lower cost if the system were installed during initial construction. For units that are already supplied by a central heating plant utilizing steam or hot water, the "conversion" to geothermal may only require piping the hot geothermal water to the existing heat exchanger and modifications such as a larger heat exchanger, larger radiators in the indivdual units or higher speed fans blowing more air over existing radiators.

The geothermal water, after it is cooled, must be disposed of, due to the high chemical concentrations in most situations. Any disposal above ground could have serious environmental effects. The most accepted method of disposal is that of reinjection of the geothermal water back into the ground. Test conditions of this means of disposal have not produced any recorded environmental or technical difficulties to date. However, certain precautions must be taken. First the reinjection well must be in a zone of high permeability. Secondly, the water temperature at the base of the reinjection well must be of sufficient temperature to maintain sufficiently high water temperature in order to prevent supersaturation of potential

scaling material, which would cause the deposit of chemicals reducing the effectiveness of the reinjection well. Finally, the reinjection well must be at least 0.6 miles (1 kilometer) away from the producing well, to prevent short circuiting of the flow, which would result in a significant reduction in wellhead temperature. The rock surrounding the reinjection well would cool to the temperature of the injected fluid, and if too close, the temperature drop could affect the production well.

In summary, geothermal space heating costs are associated with a number of variable factors including:

- Production well costs
  - Depth of well
  - Problems encountered during drilling
  - Flow rate of water (may require more than one well)
- Distribution costs
  - Distance to heat load
  - Size of piping (flow rate)
  - Insulation required
  - Heat exchanger
  - Modifications to existing system
- Reinjection costs
  - Costs of drilling reinjection wells
  - Piping to well

As previously noted there are no standardized costs. Each situation must be viewed seperately. Once the total costing is estimated, the job is not done. Present value analysis and life cycle costing must be used as tools to determine if the project is to be undertaken.

The following sections of this thesis address two separate Engineering studies which relate to the application of geothermal heat to space heating requirements at the Naval Air Station, Fallon, Nevada. These two studies are synopsized in the following chapters. The results of each engineering study are used to develop a benefit/cost analysis with emphasis on key variables. Results of this extension of economic analysis relating to the two engineering studies are outlined in the conclusions and recommendations found in the final chapter.

III. CHINA LAKE ENGINEERING STUDY

In an effort to utilize alternative energy resources, the U.S. Navy is exploring the partial or total conversion of Naval Air Station, Fallon, Nevada's present heating plant to a geothermal system. The State of Nevada has long been known for its hot springs and wells which are scattered over the entire state. NAS Fallon, which is approximately 60 miles East, Southeast of Reno, lies near the Carson Sink. This area encompasses the Stillwater-Soda lake Region in addition to Fallon and is classified

a Known Geothermal Resources Area (KGRA) by the State of Nevada [11]. As a geothermal reservoir appears to be readily available at NAS Fallon, an engineering study was completed for the possible conversion of the existing heating system [12]. This study will be presented as a frame-work for further benefit/cost analysis in later sections. In presenting this engineering study certain engineering terms will be used; terms that are unfamilar are defined in Appendix A.

NAS Fallon is presently heated by fossil fuel developed steam, high temperature water, and natural gas. The annual (1978) fuel bill is $437,000 per year. Although the geothermal resources at Fallon have not been developed, and their exact nature is unknown, this study will examine a range of several well temperatures to determine which range would be effective in utilizing the geothermal resources as an alternative energy source.

In considering a total conversion to geothermal energy, the Base was divided into nine areas and each will be considered as an independent system. At Fallon, as at other military installations, various areas such as housing and industrial complexes are usually separated. In outlying areas the complexes are often serviced by a separate heating plant; such is the case at Fallon. Figure 4 designates the areas. The letters along the distribution system are used as distance markers. Dimensions between various letters are detailed in Table I.

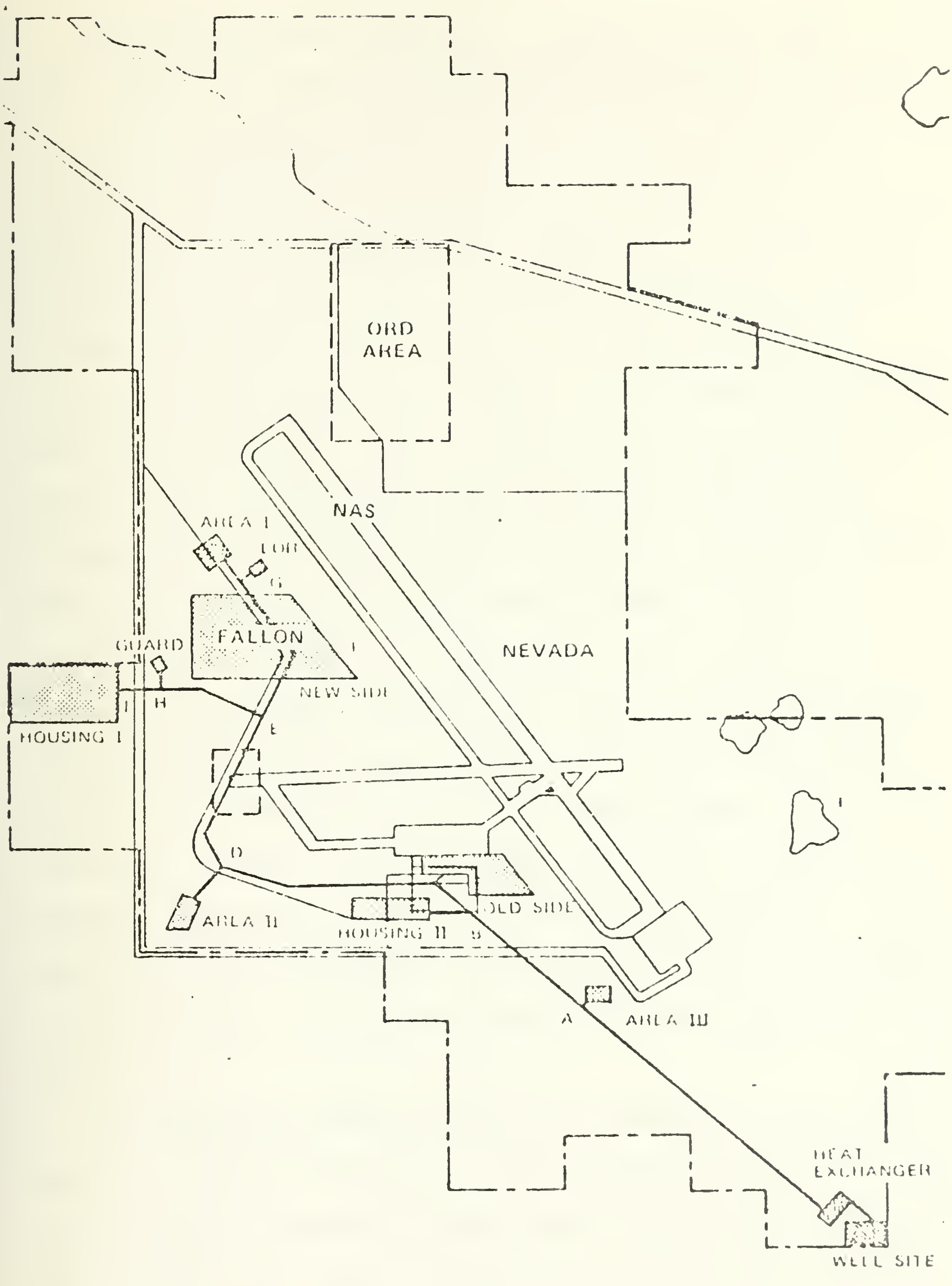


Fig. 4. Map of Naval Air Station Fallon, Nevada

Thd distribution system was designed to use steel pipe with 2 1/2 inches of insulation, and since the runs are relatively short, heat losses in the distribution system were assumed to be negligible, therefore, they were not considered separately. However, the losses were included in the heat load calculated in the design of the system. The heat loads for each area were calculated using the design capacity as Run I, which shows the maximum usage by the system. Run II depicts the lower bounds of energy usage and was calculated using the total British Thermal Unit (BTU) load for each month (as provided in the Defense Energy Information System II Report), divided by the number of hours in the month. This yielded an average rate of BTU's supplied per hour. To be realistic, the geothermal system was designed to supply twice the rate of the highest value of the computations. In addition, the New Side area contained a 50% increase for probable expansion, and Housing Area I contained an additional load for 70 dwellings which currently are being planned. Table II lists the results of heat loads for Runs I and II.

The flow rate through the piping system was calculated. Knowing the heat load and ΔT (difference between supply and return lines), the gallons per minute (gpm) can be calculated and the pipe size can be determined. After calculating the cost per foot of pipe, valves and fittings, insulation, casing, labor/trenching, and the two pipe distribution systems, the

TABLE I. DISTRIBUTION SYSTEM DIMENSIONS

Section of Pipe			Distance (feet)
Well Site to Heat Exchanger			0
Heat Exchanger to A			10,400
A	to	B	3,000
A	to	Area III	400
B	to	C	640
B	to	Housing Area C	0
C	to	D	4,100
C	to	Old Site	400
D	to	E	5,280
D	to	Area II	1,500
E	to	H	2,400
H	to	I	1,200
I	to	Housing Area I	0
H	to	Guard Station	160
E	to	F	2,300
F	to	New Site	0
F	to	G	1,400
G	to	LOX	480
G	to	Area I	800

TABLE II. SPACE HEATING AND HOT WATER LOADS

Area	Run I Design Load In BTUH	Run II Computed Load In BTUH
Area I	5,000,000	4,425,000
LOX	100,000	88,500
New Side	75,000,000	44,250,000
Guard Shack	40,000	35,000
Housing Area I	17,760,000	10,761,600
Area II	2,600,000	2,301,000
Old Side	13,170,000	11,655,500
Housing Area II	6,080,000	5,380,800
Area III	350,000	309,000

TABLE III. COST PER LINEAR FOOT OF DISTRIBUTION SYSTEM

Pipe diameter in inches

	3-1/2	4	5	6	8	10	12	14
$/ft	19.20	26.40	33.61	41.24	54.17	68.66	78.56	99.76

final cost per linear foot of the distribution system is given in Table III.

The size of the heat exchanger was calculated utilizing references 13 and 14. Various sizes of heat exchangers were calculated for several different well temperatures.

Assumptions regarding efficiencies and other parameters of design were consistent with accepted industrial standards. The size of pumps required for the recirculation water and the geothermal well are indicated in the study. In calculating these values the authors of the study assumed a pump efficiency of 90%. The geothermal well was assumed to have a 1000 ft. head loss for the well plus, the head loss from the heat exchanger. Pump costs were estimated at $400 per horsepower for the well pumps and $100 per horsepower for the recirculation pumps. The smaller the heat exchanger the greater the volume of well fluid that must be pumped through the exchanger to maintain a constant ΔT. Thus, the smaller the exchanger the more horsepower required for the geothermal well.

To determine the final pricing of the system the following cost assumptions were used:

A cost of $45,000 per MBTUH was used for the retrofit of the existing steam/hot water system.

A cost of $12,000 per MBTUH was used for the retrofit of the existing forced air natural gas heating system.

A cost of $500 per dwelling was used for the retrofitting of housing units.

A one-time rehabilitation cost for the Old Side Area was assumed to be $130,000.

Well costs were assumed to be $20,000 per well for either production or reinjection.

The maintenance cost for either system was assumed to be the same.

The various costs for both Run I and II are diagramed in Figures 5 and 6. The authors utilized three (3) flow volumes from the geothermal well; that of 100, 300 and 500 gpm. The lower the well flow rate and temperature the more wells needed to supply the BTU's required, thus well costs increase at lower flow rates and lower temperatures. The charts also indicate cost differences between reinjection and no reinjection. The expected total dissolved solids (TDS) is approximately 4000 parts per million (PPM) most of which is sodium chloride. The well effluent may be used for cattle watering but not on a regular basis. The expectation is that the water will have to be reinjected [15].

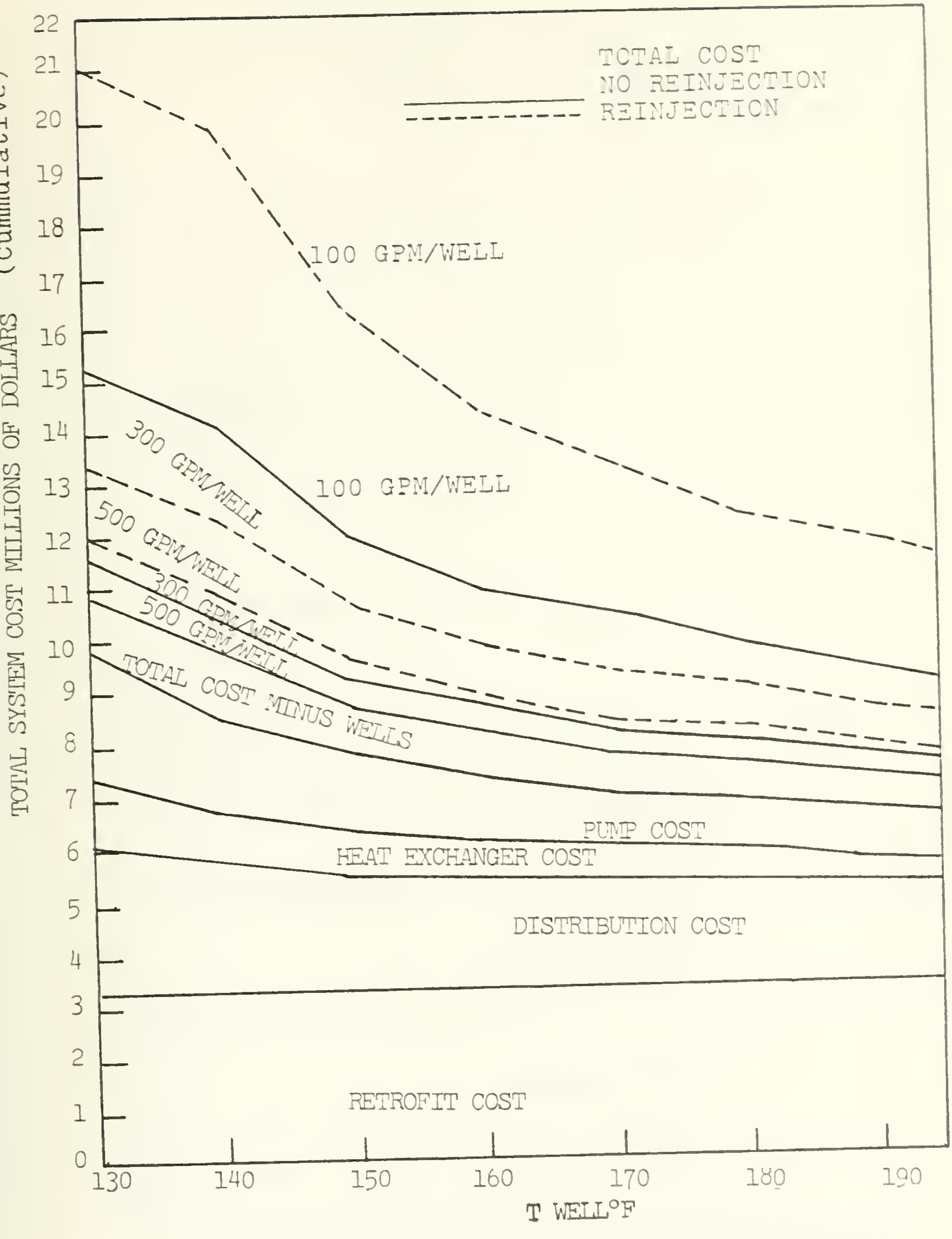


FIG. 5. Cost Results, Run I, China Lake Engineering Study

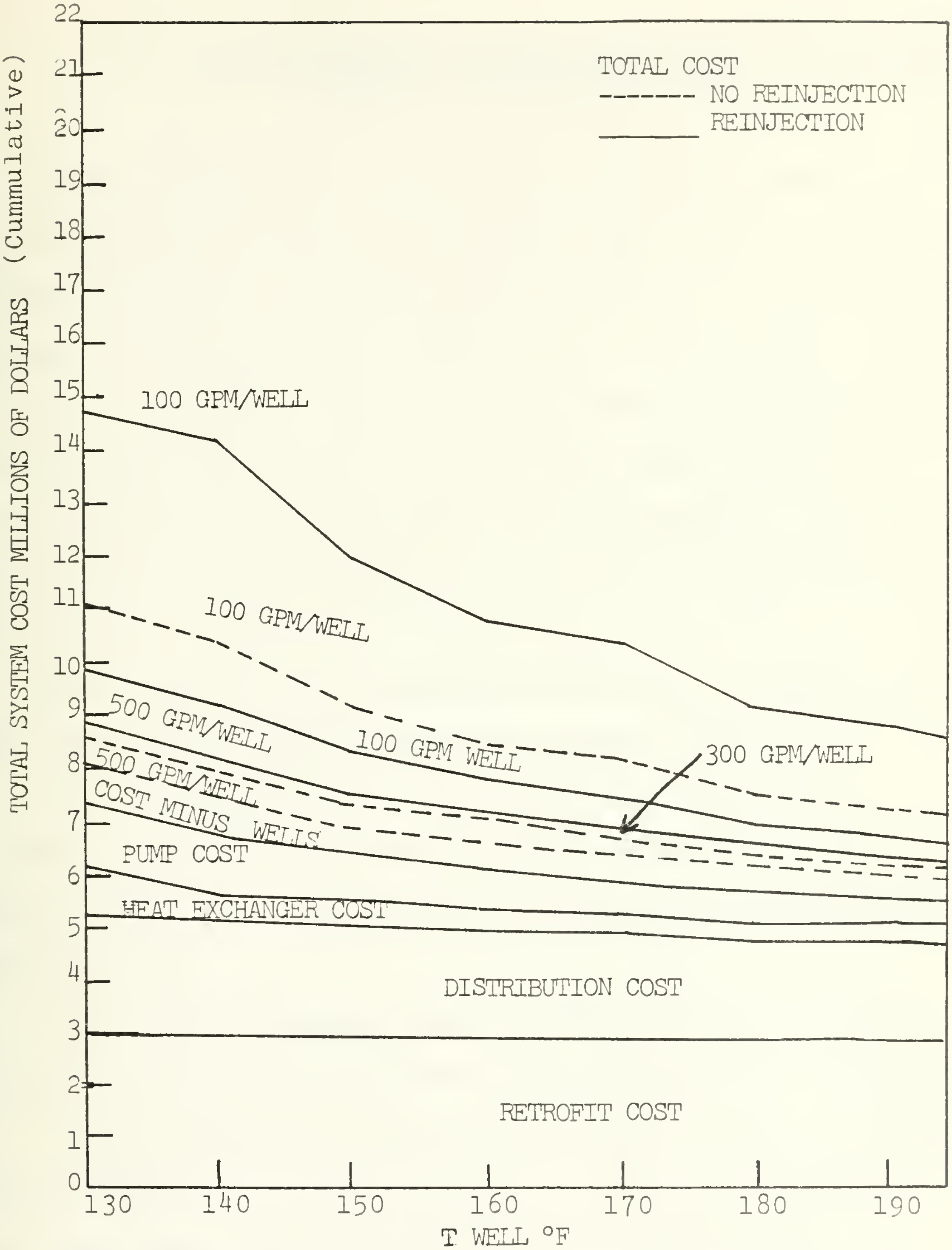


Fig. 6. Cost Results, Run II, China Lake Engineering Study

IV. WESTERN DIVISION, NAVAL FACILITIES ENGINEERING COMMAND, ENGINEERING STUDY

A second independent engineering study was conducted by the Western Division of the Naval Facilities Engineering Command (WestDiv.) concerning the utilization of geothermal energy for space heating at NAS Fallon, Nevada [16]. This study was in greater detail than the China Lake evaluation; but the most significant difference was that the WestDiv study concentrated on converting only a portion of the base to geothrermal space heating versus a total base conversion in the China Lake study.

Specifically, the alternatives reviewed by WestDiv were: (the numbering is that used by the WestDiv study)

1) Obtaining water from a geothermal well at a minimum temperature of 210°F (99°C) and converting only the area referred to as New Side (Appendix A) to geothermal space heating.

2A) Obtaining water from a geothermal well at 160°F (71°C) and using it to heat the two housing areas (Appendix A).

2B) Utilizing the return water from alternative number one to heat the housing areas prior to returning to the heat exchanger. This is in reality an extension of alternative number one.

The study defined the existing system in detail, then in even greater detail costed out each aspect of retrofit to utilize the geothermal hot water. The costing included such items as:

The size of piping from the main line to each building, considering the type of heating units in the building or costing new heating units to be compatible with the geothermal hot water.

Friction loss in the pipe and flow rates needed for each individual pipe.

Detailed drilling costs

Design factors based on historical weather data and heat loads.

All energy now consumed by the system was calculated and by subtracting the extra pumping energy (which is also developed in the study) required by the geothermal system, a net total energy savings was obtained. This process of determining a new energy savings was developed for all three of the alternatives.

The study then took the retrofit costs and totalled them to obtain a construction cost estimate. A Naval Facilities Engineering Command standard design cost was assumed (6% of the construction costs) and with the net energy savings economic calculations were made. For each alternative, design costs, construction costs, and annual energy savings were determined.

The study then assumed the project was 5 years from being completed and utilizing guidelines of the Energy Conservation Investment Program to FY 83. The economic life of 25 years was assumed and calculations were based

on an 8% differntial inflation rate (8% increase above the general price levels) then discounted at 10%.

The results are as follows:

1)	Total project cost	\$6,512,490
	Discounted savings	\$4,972,073
	Simple payback period	22.65 Years
2A)	Total project cost	\$6,095,766
	Discounted savings	\$3,148,957
	Simple payback period	33.47 Years
2B)	Total project cost	\$3,652,988
	Discounted Savings	\$3,480,005
	Simple payback period	18.12 Years

Combining alternative 1 and 2B

Total project cost	\$10,165,478
Discounted savings	\$ 8,452,078
Simple payback period	21.33 Years

V. ECONOMIC EXTENSION OF STUDIES

This section discusses several approaches to extending the two previously outlined studies, particularly in the area of economic cost/benefit impact. It is not within the scope of this thesis to generate a whole new set of cost data; however, it is felt that a closer examination of the "benefits" will bring the overall economic viability of this project into sharper focus. The area of benefits, which is basically the fossil fuel costs saved, presents a significant problem of price projection particularly in light of recent oil price increases. This problem is even more difficult when an accurate projection is attempted over a twenty-five year period (1978-2003). In an attempt to diminish this problem, the projected fuel costs were established over a wide range of inflation rates (4% to 20% annually).

A. THE CHINA LAKE STUDY

The fuel costs versus inflation rate figures from the China Lake study are shown in Fig. 7. The first year's fuel cost total of $437,000 corresponds to the 1978 fuel consumption figure used in the previously outlined China Lake study. This figure was escalated by the annual inflation rate over a twenty-five year projected life and then converted to a present worth using a 10% discount factor. The use of a 10% discount factor is prescribed

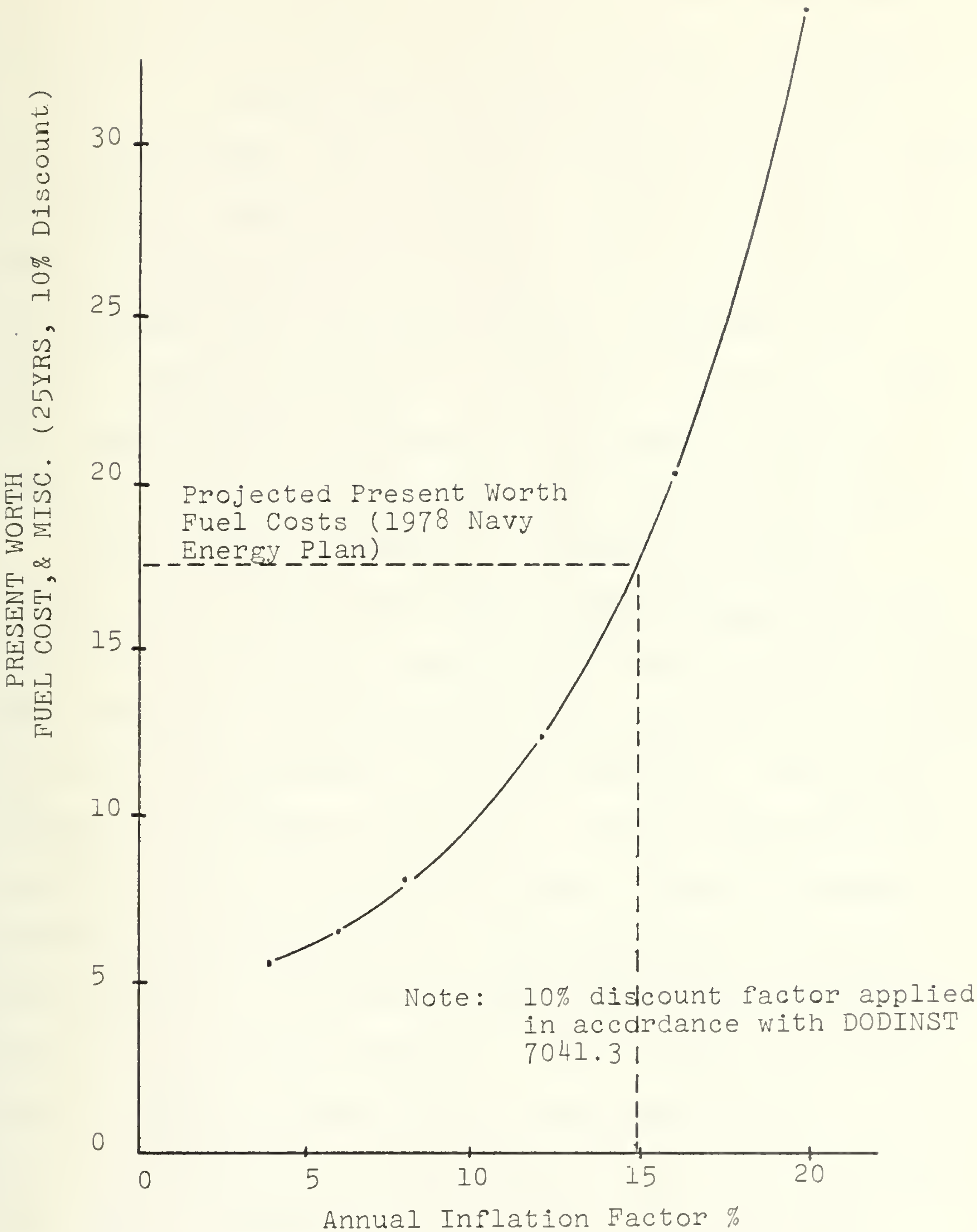


Fig. 7 NAS FALLON, NEW NET PRESENT WORTH-FUEL COSTS
(25 YEAR LIFE)

by DOD Instruction 7041.3. The discounting techniques employed in this thesis are based on guidance contained in Ref. 17. Although the use of other discount rates may be justifiable under certain circumstances (see articles by William J. Baumol and Jacob A. Stockfish [18] and Elmer B. Staats [19]), the use of a 10% factor was felt to be academic and therefore employed throughout this thesis. Figure 7 indicates a potential "savings" in fuel costs ranging from $5,503,000 (at 4% annual inflation factor) to $34,138,000 (at 20% annual inflation factor).

In an attempt to identify a resonable projected savings, fuel pricing data from the Navy Energy Plan [20] for fuel oil and natural gas for the fiscal year 1977 through 2000 were used. Figure 8 shows the projected price increases for each of these fuels in constant dollars. These cost figures are reflected in Table IV. Yearly percentage increases in price are also calculated. These percentage increases (beginning with the 1978 percentage increase) were applied to the current actual (1978) fuel costs at NAS Fallon as shown on Table V. The initial cost split between natural gas and fuel oil was based on the actual cost incurred for each type of fuel. By applying these yearly increases to the initial 1978 costs (and interpolating values for those years not shown on Table IV) a total fuel cost for the years 1978 to 2003 (a 25 year period) was generated. Since the price increases were based

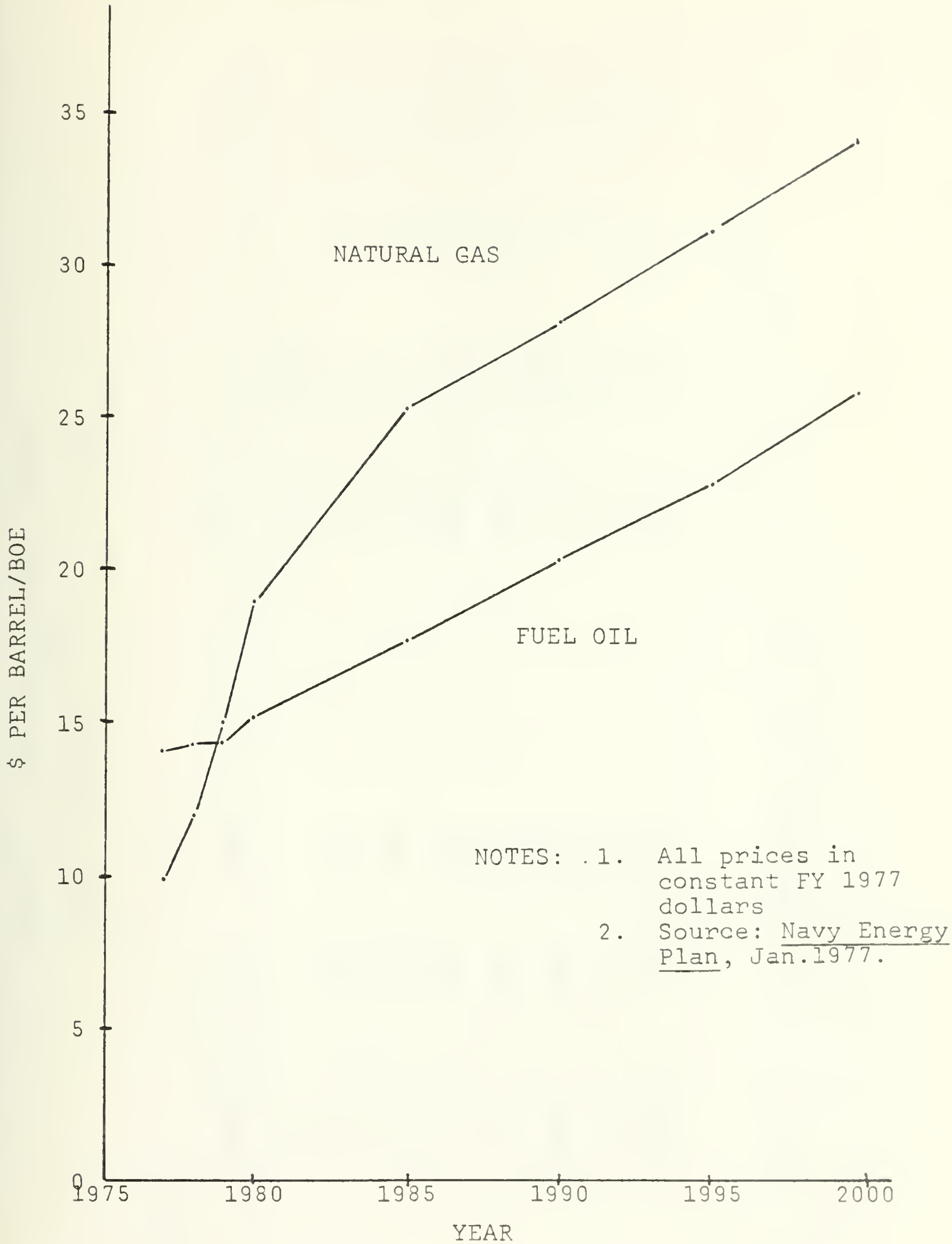


Fig. 8 PROJECTED FUEL PRICES FY 1977 TO FY 2000

TABLE IV. PROJECTED ENERGY PRICES
AND
PRICE INCREASE* FY 1977 TO FY 2000
(prices in 1977 dollars per barrel/BOE)**

Fuel Oil				Nat. Gas			
YR.	COST $	Δ	%Incr	YR.	Cost $	Δ	%Incr
1977	14.11			1977	9.90		
1978	14.35	.24	1.7%	1978	12.00	2.10	21.2%
1979	14.59	.24	1.7%	1979	15.00	3.00	25.0%
1980	15.14	.55	3.8%	1980	19.00	4.00	26.7%
1985	17.75	2.60	17.2%	1985	25.12	6.12	32.2%
1990	20.36	2.60	14.7%	1990	28.09	2.97	11.8%
1995	22.97	2.61	12.8%	1995	31.05	2.96	10.5%
2000	25.88	2.91	12.7%	2000	34.02	2.97	9.6%

*SOURCE: Appendix C, Navy Energy Plan, Jan. 1977.

**BOE = Barrel of Oil Equivalent = 5.8 million BTU

TABLE V. NAS FALLON, NEVADA PROJECTED FUEL COSTS

(in constant 1978 $)

FISCAL YEAR	FUEL OIL($)	NATURAL GAS ($)	TOTAL($)
1978	342.270	94,730	437,000
1979	348,089	118,413	466,502
1980	361,316	150,029	511,345
1981	373,745	159,691	533,436
1982	386,174	169,353	555,527
1983	398,603	179,015	577,618
1984	411,032	188,677	599,709
1985	423,463	198,338	621,801
1986	435,913	203,019	638,932
1987	448,363	207,700	656,063
1988	460,813	212,381	673,194
1989	473,263	217,062	690,325
1990	485,711	221,742	707,453
1991	498,145	226,399	724,544
1992	510,579	231,056	741,635
1993	523,013	235,713	758,726
1994	535,447	240,347	775,794
1995	547,883	245,025	792,908
1996	561,883	249,739	811,622
1997	575,883	259,453	830.336
1998	589,883	259,167	849,050
1999	603,883	263,881	867,764
2000	617,464	268,547	886,011
2001	631,464	273,261	904,725
2002	645,464	277,975	923,439
TOTAL($)	12,189,746	5,345,713	$17,535,459

NOTES:
1) The fuel oil/natural gas cost breakdown for 1978 was based on actual consumption figures.
2) Each initial 1978 cost figure was then escalated by the percent increase factor shown in TABLE IV. (previous page)
3) These escalated costs were then summed to get a total for that year. Summing the total $ column produces an estimated present worth fuel cost.

on constant year cost figures applied to 1978 prices, the sum of the columns in Table V. will yield a present value price without the necessity of discounting. These calculations result in a total present value fuel cost of $17,535,000. Comparing this to the cost-inflation graph in Figure 7, the Navy Energy Plan projects an annual inflation factor of approximately 15%.

The use of the Navy Energy Plan costing data for fuel oil and natural gas, resulted in the generation of a single best estimate of the present worth 25-year fuel consumption for Fallon, Nevada. This "narrowing of options" was next applied to the project cost data generated in the China Lake study previously depicted in graphic form in Figures 5 and 6. These figures present a significant array of cost alternatives depending upon well head temperature, effluent quality (reinject or pond), and anticipated flow rate. An attempt was made to identify a "most likely" set of conditions that could be expected at NAS Fallon which would fix several of these parameters and allow for the development of a most likely cost model. Once this was done, it could be compared to the "most likely" benefits derived above, culminating in the calculation of a single cost benefit ratio for the project. Alternatively based on the number of variables remaining after this procedure, a family of benefit/cost curves could be generated which would address the basic question of this section; that is, using what is now known, applying a reason-

able set of assumptions, and eliminating or fixing as many variables as possible, is the project basically economical?

The determination of the "most likely" outcome of well drilling at NAS Fallon was the topic of several conversations with Dr. Carl Austin and Dr. J. Whelan [21] of the Geothermal Utilization Division, Public Works Center, Naval Weapons Center, China Lake, California. Based on their extensive background in geothermal energy and intimate knowledge of the NAS Fallon project, a best estimate of the well head conditions is stated as follows:

Projected Wellhead Temperature 150°F

Projected Effluent Quality 40000PPM Sodium Chloride

During these discussions it was noted that the likely wellhead temperature could easily exceed this figure by a considerable margin (100°-200°F), and that it was rather unlikely that the temperature would drop below 150°F. The anticipated brine content of 4000PPM although significantly lower than that of sea water (35,000PPM) could be used for periodic cattle watering but would most likely need to be reinjected.

The application of the above information to the cost charts Figures 5 and 6 results in development costs vary only with anticipated flow rate. The benefits or savings calculated earlier as a function of annual fuel inflation rate was combined with the cost data in TABLE VI resulting in the calculation of cost/benefits ratios for varying flow rates and fuel inflation factors. This information is presently graphically in Figures 9 and 10.

Observations made concerning the results of this analysis are as follows:

1. Benefit/cost ratios are extremely sensitive to fuel inflation rate and somewhat less sensitive to flow rate per well.

2. The lower benefit/cost break even point of Run II Figure 10 when compared to that of Run I Figure 9 is a result of Run II's significantly lower overall capital investment.

3. The impact of flow rate per well on the break even point is diminished in Run II compared to Run I, indicating that flow rate sensitivity increases with overall system size (and cost).

4. Benefit/cost ratios were only calculated on a basis of 150°F wellhead temperature effluent with reinjection. The overall project economics of this project are extremely sensitive to slight increases in wellhead temperature. A slight (10° to 20°F) increase in temperature will economically justify this project at a very low annual fuel inflation rate figure.

TABLE VI. BENEFIT/COST RATIO CALCULATIONS

RUN I

INFL. RATE	"BENEFIT" $Mil	GPM/WELL 100 Cost $Mil	B/C	300 Cost $Mil	B/C	500 Cost $Mil	B/C
4	5.55	16.25	.34	10.65	.52	9.65	.58
6	6.55		.40		.62		.68
8	8.15		.50		.77		.84
10	10.00		.62		.94		1.04
12	12.45		.77		1.17		1.29
14	15.50		.95		1.46		1.61
16	20.20		1.24		1.90		2.09
18	26.00		1.60		2.60		2.69
20	34.00		2.09		3.40		3.52

RUN II

INFL. RATE	"BENEFIT" $Mil	GPM/WELL 100 Cost $Mil	B/C	300 Cost $Mil	B/C	500 Cost $Mil	B/C
4	5.55	10.00	.56	8.75	.67	7.40	.75
6	6.55		.66		.79		.89
8	8.15		.82		.99		1.10
10	10.00		1.00		1.21		1.35
12	12.45		1.25		1.51		1.68
14	15.50		1.55		1.88		2.09
16	20.20		2.02		2.45		2.73
18	26.00		2.60		3.15		3.51
20	34.00		3.40		4.12		4.59

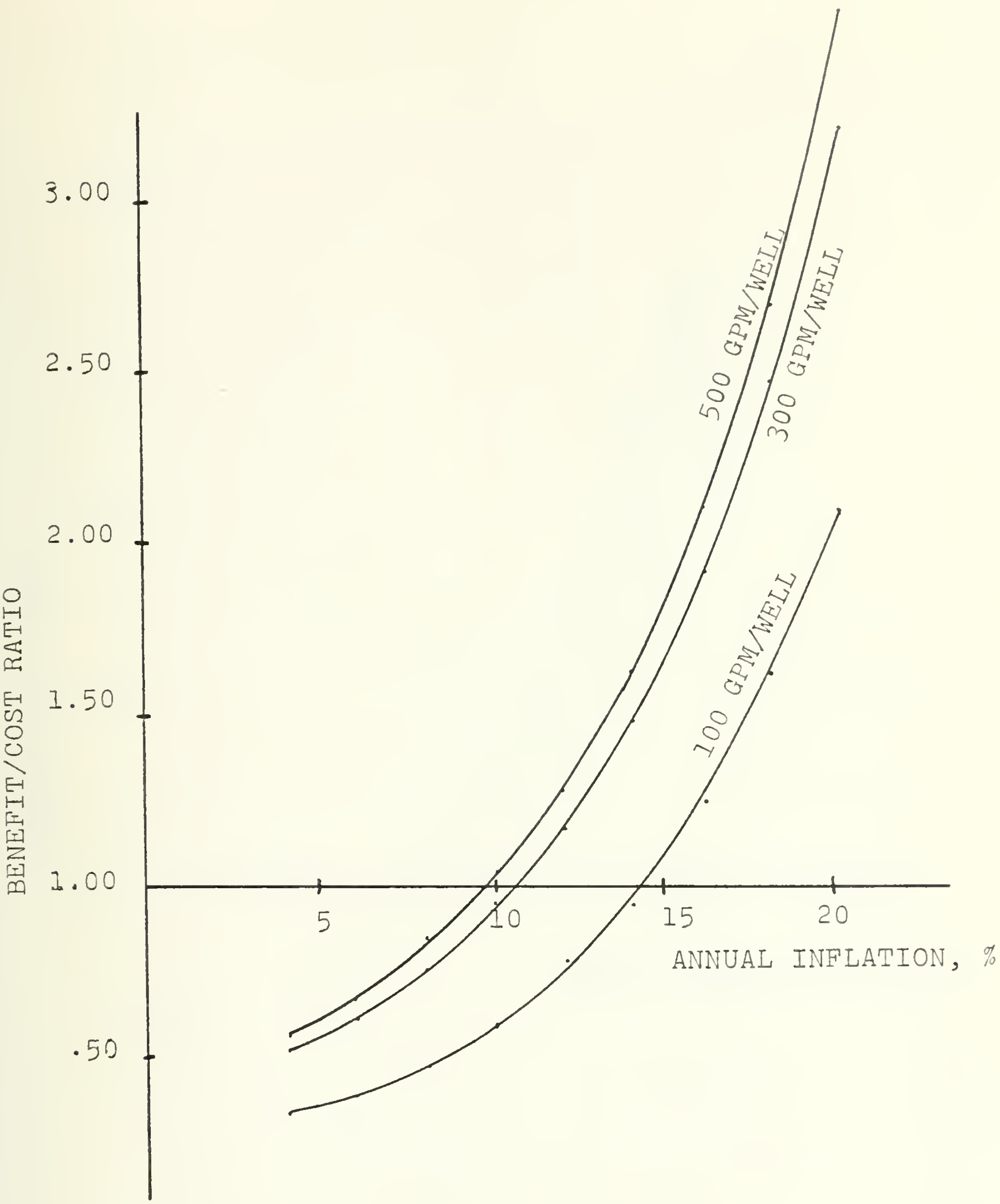


FIG. 9 BENEFIT/COST RATIO vs. ANNUAL FUEL INFLATION RATE RUN I (UPPER BOUND) 150°F WELL OUTPUT.

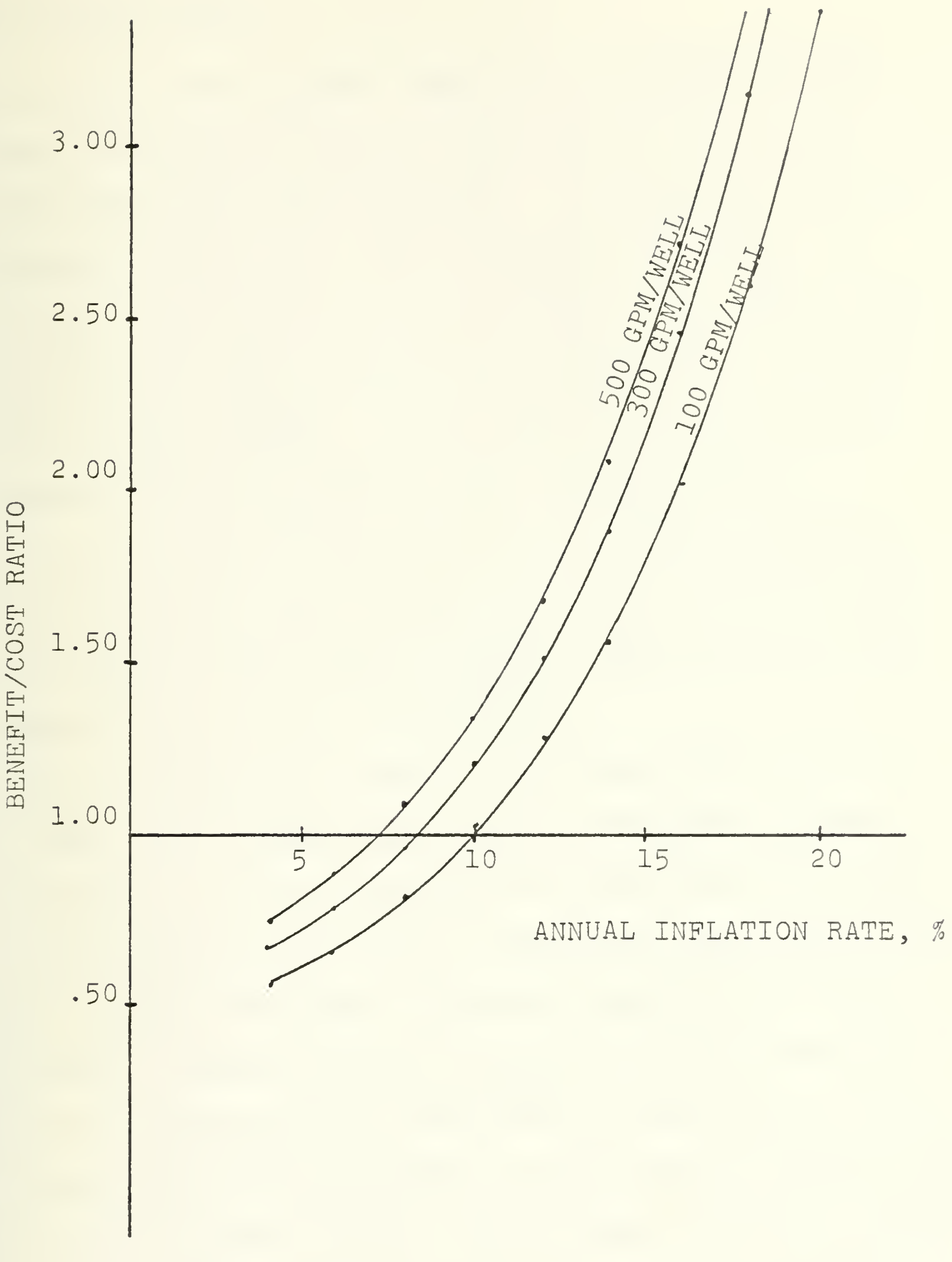


Fig. 10 BENEFIT/COST RATIO vs. ANNUAL FUEL INFLATION RATE RUN II (LOWER BOUND) 150°F WELL OUTPUT.

3 THE WESTDIV STUDY

In assessing the economic impact of the WESTDIV Study, a attempt was made to parallel the analysis made in the (hina Lake study outlined previously. The assumptions made nd procedures used, along with the general scope of the ESTDIV study alternative, make it difficult to compare the esults of each of these alternatives side-by-side with the hina Lake study. Rather, it was felt that the generation f a separate set of "benefit" costs, along with the alculation of benefit/cost ratios as a function of annual uel price inflation, would result in a set of graphs, which ould provide some qualitative insight relating to the over-ll feasibility of these alternatives.

For each alternative, the FY 1979 "cost" and "benefit" igures were used without applying the escalation factors. his was done to utilize figures for a base year which most early fits the base year used in the China Lake study. The benefit" figures were then inflated by varying inflation ates over the twenty-five year project life and then dis-ounted to a present worth value using a 10% discount factor. he tables contained in reference 5 were used to generate the resent worth "benefit" costs. The project costs and project enefits, along with the benefit/cost rations are tabulated y alternative in TABLE VII. These benefit/cost ratios, alculated as a function of annual fuel inflation rate, re shown in Figure 11. Although alernative 2B appears to e the most "economical" alternative, it must be remembered hat it is not an independant alternative. It assumes the

availability of geothermally heated feed water at the "new side" area of the base and therefore does not include the cost of the well system. This leaves alternatives 1+2B, 1 and 2A respectively, all crossing the break even point between a 10% to 15% annual fuel inflation factor.

TABLE VII. COMPUTATION OF BENEFIT/COST RATIOS
WESTDIV. STUDY

ALTERNATIVE	INFL. RATE %	PV OF ANNUAL BENEFITS AT 10% DISC. ($ Mil)	COSTS ($ Mil)	RATIO B/C
1	2	1.775	4.83	.367
	4	2.123	"	.440
	6	2.5753	"	.533
	8	3.1672	"	.656
	10	3.9492	"	.818
	15	7.4087	"	1.534
	20	14.8057	"	3.065
2A	2	1.1254	4.5194	.249
	4	1.3461	"	.298
	6	1.6326	"	.361
	8	2.0078	"	.444
	10	2.5035	"	.554
	15	4.6966	"	1.039
	20	9.3858	"	2.077
2B	2	1.2439	"	.460
	4	1.4878	"	.550
	6	1.8045	"	.667
	8	2.2193	"	.821
	10	2.7672	"	1.024
	15	5.1911	"	1.920
	20	10.3743	"	3.838
1+2B	2	3.0191	7.5334	.401
	4	3.6112	"	.478
	6	4.3798	"	.581
	8	5.3864	"	.715
	10	6.7163	"	.892
	15	12.5998	"	1.673
	20	25.1799	"	3.342

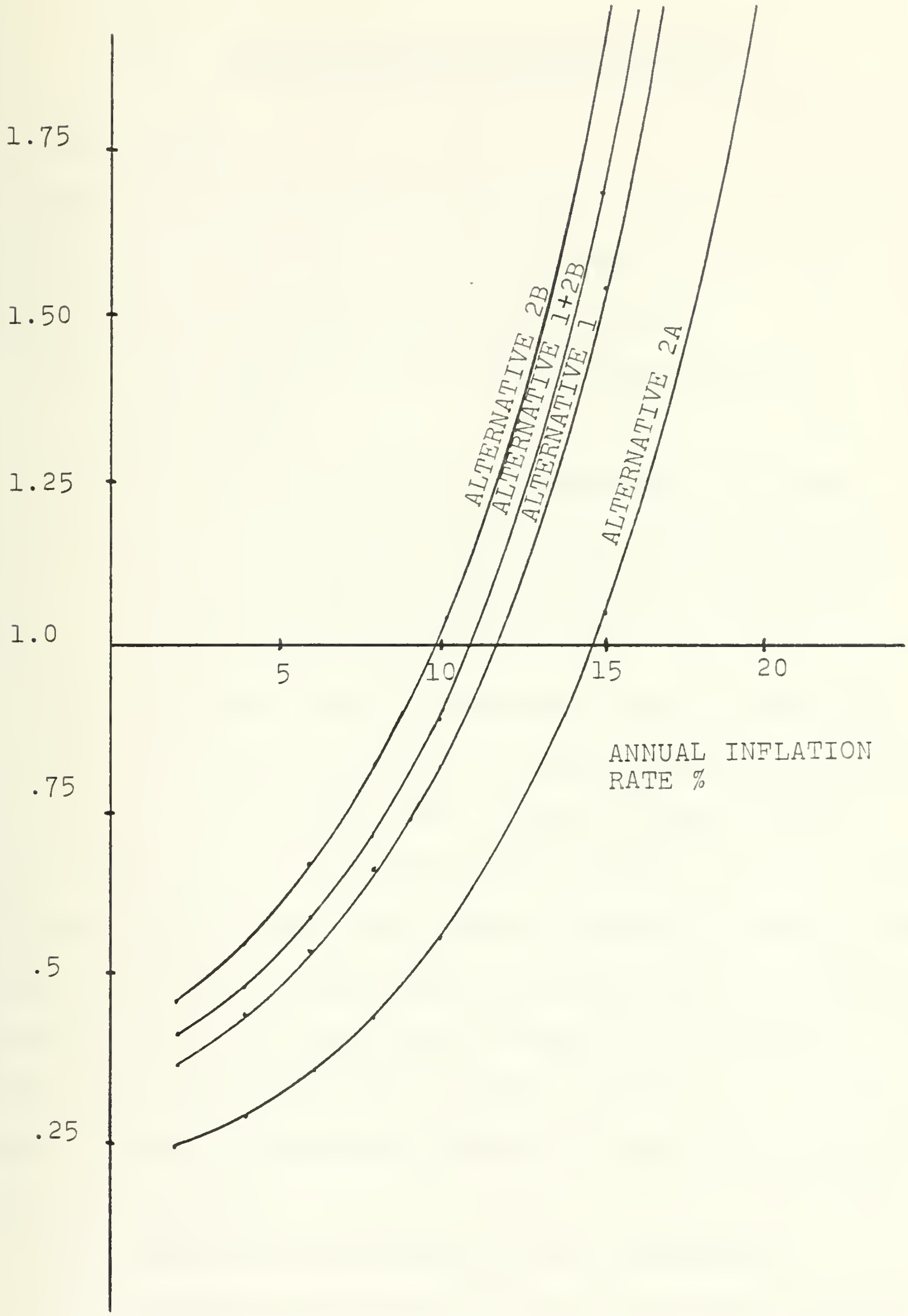


FIG. 11 BENEFIT/COST RATIO vs. ANNUAL FUEL INFLATION RATE. (WESTDIV STUDY)

VI. CONCLUSIONS AND RECOMMENDATIONS

A. CONCLUSIONS

Results of the economic extensions addressed earlier in this thesis indicates that a geothermal conversion at NAS Fallon is economically sound given:

(1). The accuracy of cost assumptions made in each study.

(2). The accuracy of the extrapolation of current fuel price trends and the continuing availability of these types of fuels over the life of the geothermal alternative.

(3). That this type of conversion may be justified on a long term basis recognizing the time value of cash flows, vice a simple payback method.

In examining and extending the economic results of each of these studies, care was taken to prevent a side-by-side comparison between them since the differences in the basic assumptions of each study would result in misleading conclusions relating to the overall feasibility of this type of energy alternative. Areas of significant difference include following;

(1). Whole base vice partial base convention.

(2). A single alternative vice a set of alternatives.

(3). Significant differences in developmental costs (i.e., drilling, piping, and heating system conversion costs).

Similarities between the studies include base design heat load assumptions, system life, and the assumption of a zero differential cost for operation and maintenance of the existing and proposed systems.

An attempt was made in the extended analysis to draw the studies closer together by applying a similar analysis to the cost and benefit results of each separate study. This was done by relating the study costs to benefits which were restated as a function of annual fuel price inflation. As shown by the various benefit/cost ratio/fuel price inflation graphs, both studies indicate economic viability at a 10-15% annual fuel price inflation factor. Due to the above study differences, however, it is felt that further comparison of the studies, or, a decision for conversion regardless of analytical method, cannot be made without further examination of several key variables which were only approximated in each study due to a lack of documented evidence.

The key variables requiring further study and confirmation includes anticipated wellhead temperature and well flow rate, an in-depth estimate of anticipated fuel inflation rates, and a more thorough examination of operation and maintenance costs of each alternative. While wellhead temperature and flow rate are a function of the underlying geological conditions at NAS Fallon, and may be more precisely predicted by field testing, a much more difficult task is the predicting of fuel prices over the next twenty-five years. This was the reason for the analytical approach in this thesis.

While a precise or even approximate prediction of an inflation rate is impossible, it might be feasible to develop a range of inflation rates within which the actual rate may tend over the life of the project. The benefit/cost ratio fuel inflation graphs developed herein facilitate this type of analytical approach. As for the differential operating and maintenance costs, a detailed estimate of this variable may reveal a trend which favors the geothermal alternative over the conventional heating plant. This was a feeling expressed by the project engineers at the Public Works Center, China Lake, [21], although due to the preliminary nature of the studies and the lack of documentation, a zero differential was assumed.

In examining the results of both alternatives in this thesis, a feeling was developed that economies of scale were present in the geothermal alternatives. The marginal cost of extending a geothermally heated distribution system to encompass the whole base would be small compared to the increase in marginal benefit derived. By expanding the system to the whole base, the capital cost of well drilling and heat exchanger installation (practically a fixed cost) could be "distributed" over a larger "benefit" base, making the "whole base" conversion alternative more economical at a lower fuel cost inflation factor than an alternative which has almost the smae capital costs spread over a much smaller "benefit" base. This observation was made by comparing the

benefit/cost-fuel inflation rate curves for each alternative. The China Lake (or whole-base) study appears to have a set of curves that rise faster and become "economical" (exceed a C/B ratio of 1.0) at a lower inflation rate than the WESTDIV Study (partial base) study graphs.

In any type of economic analysis, the choice of analytical methods should be carefully chosen. Employing only a single method or a method not particularly suited to the program or alternatives being analyzed can result in extremely misleading conclusions. The various methods of economic analysis commonly employed [22] were reviewed and a combination of net present value and benefit/cost ratio methods with some sensitivity analysis was chosen to be used in this thesis. Simple payback methods were disregarded because of the relatively long life of this system and the high capital cost involved.

An important assumption of both studies, although not specifically mentioned in either, is the assumed continuing availability of fossil fuels (fuel oil and natural gas) over the next twenty-five years. The Navy Energy Plan [20] specifically discusses the prospect of depletion of these resources early in the twenty-first century, which gives rise to a final observation. This thesis addressed the general topic of conversion of the existing heating plant at NAS Fallon to a specific alternative; that of a geothermally derived heat source. It is felt that this may not be the current alternative. Prior to a decision on conversion to a geothermal heat source being made, the possibility of a

coal-fired heat source should be examined. It would appear that this alternative may not have the tremendously high cost of initial capital expenditures that are present in the geothermal alternative. Although an in-depth analysis of a coal-fired alternative is beyond the scope of this thesis, it is felt that an inquiry into this alternative along with its comparison to geothermal would result in the selection of a system which would maximize cost savings, reliability, and independence from current fossil fuel use.

The ever changing (and apparently ever worsening) world oil situation may eventually drive a decision for conversion away from such fuels as fuel oil and natural gas at not only NAS Fallon, but at all Navy shore activities as well. NAS Fallon, with its unique geothermal resource, represents an opportunity for energy independence with regard to base heating. Granted, it is but a small part of the total Navy shore establishment; however, as time passes this type of decision is going to have to be faced at more and more Navy activities.

B. RECOMMENDATIONS

1. Geothermal well tests be pursued.

2. Whole-based or partial-base conversion analysis be done. Examine marginal benefits and costs.

3. Employ present worth-type analysis vice simple payback in future analyses. Examine sensitivity of basic variables, such as fuel price inflation.

4. In light of a seemingly ever-worsening fuel situation in the U.S., and the prospect of fuel oil/natural gas depletion, a coal conversion alternative should also be studied and compared to the geothermal option.

5. Pursue an active conversion program provided:

a. Subsequent investigation of the above variables support those assumptions already made.

b. Subsequent economic analysis of the conversion alternative results in a cost benefit to the Navy.

APPENDIX A
GLOSSARY OF TERMS

British Thermal Unit (BTU) - The quantity of heat required to raise the temperature of one pound of water one degree fahrenheit.

British Thermal Unit per Hour (BTUH) - The quantity of BTU's delivered or consumed in one hour.

Energy Conservation Investment Program (ECIP) - A special NAVFAC managed program sponsored by the Chief of Naval Operations which provides funds for the accomplishment of energy conservation related projects.

Effluent - Liquid discharged as waste such as water used in an industrial process.

Head Loss- Liquid pressure is often caused by the weight of the overlying liquid and this is referred to as pressure head or simply head. The pressure or head is consumed (and hence lost) in forcing the fluid along, against the resistance caused by the portions of the pipe in contact with the liquid.

Heat Exchanger - A device (as an automobile radiator) for transferring heat from one fluid to another without allowing them to mix.

Horsepower - A unit of work equal to 550 foot-pounds per second.

MBTUH - Million BTU per Hour. (Term utilized in the China Lake Study.)

Δ T - Symbol used to indicate "change in temperature".

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